PROPOSED

Covered Source Permit 0054-01-C Application Review
Application No. 0054-05

Applicant:	**Hawaiian Commercial & Sugar (HC&S) Company**
Facility:	**Puunene Sugar Mill**
Located At:	Puunene, Maui
Mailing Address:	P.O. Box 266 Puunene, Maui 96784
Telephone::	(808) 877-0081
Facimile:	(808) 871-7663
UTM Coordinates:	764,528 m E, 2,309,899 m N, Zone 4 North American Datum of 1927 (NAD 27) 764,823 m E, 2,309,685 m N NAD 83

EQUIPMENT DESCRIPTION and SPECIFICATIONS

TABLE 1 - BOILERS 1, 2, and 3 DESCRIPTIONS AND SPECIFICATIONS
(and 3 NON-PERMITTED TURBINE GENERATORS):

		BAGASSE	**COAL**	**FUEL OIL SPEC USED OIL**
BOILER 1	**STACK 1**			
Manufacturer	Riley Stoker			
Model No.	RX-29			
Serial No.				
Rating Heat Input		212 MMBtu/hr	192 MMBtu/hr	173 MMBtu/hr
Fuel Consumption		50,560 lb/hr	10,127 lb/hr	8,650 lb/hr 1,236 gal/hr
Steam Output		125,000 lb/hr	137,500 lb/hr	135,000 lb/hr
Sulfur Content			0.5% by wt	2.0% by wt fuel oil
				0.75% spec used
4 Oil Burners				
Manufacturer	Coen	Each burner burning propane at maximum potential of 237,500 Btu/hr		
Model No.	CRD-DAZ 26 (2010)			
BOILER 2	**STACK 1**			
Manufacturer	Riley Stoker			
Model No.	RX-29			
Serial No.				

Rating Heat Input		212 MMBtu/hr	192 MMBtu/hr	173,000 MMBtu/hr
Fuel Consumption		50,560 lb/hr	10,127 lb/hr	8,650 lb/hr 1,236 gal/hr
Steam Output		125,000 lb/hr	137,500 lb/hr	135,000 lb/hr
Sulfur Content			0.5% by weight	2.0% by wt fuel oil
				0.75% spec used
4 Oil Burners	2 Coen CRD-DAZ 26 (2006)	Each burner burning propane at a maximum potential of 237,500 Btu/hr		
Manufacturer	2 Peabody			
Model No.	H-23 ABT			
BOILER 3	**STACK 2**			
Manufacturer	Foster Wheeler			
Model No.	RX-41-WW			
Serial No.				
Rating Heat Input		568 MMBtu/hr	437 MMBtu/hr	392 MMBtu/hr
Fuel Consumption		147,917 lb/hr	43,152 lb/hr	19,600 lb/hr 2,801 gal/hr
Steam Output		290,000 lb/hr	290,000 lb/hr	290,000 lb/hr
Sulfur Content			0.5% by wt	0.5% by wt fuel oil
				0.5% spec used
4 Oil Burners		Each burner burning propane at a maximum potential of 300,000 Btu/hr		
Manufacturer	Coen			
Model No.	CPF 30 (1997)			

Abbreviations	
Btu = British thermal units	lb = pound
gal = gallons	spec used = specification used oil
hr = hour	wt = weight

1. There are three (3) turbine generators. The turbines at the Puunene Mill are not emission sources. Therefore, the turbines are exempt and not in the permit.
2. All three (3) boilers use small amounts of propane for start-ups to the oil burners.
3. 2 - Venturi wet scrubber systems, one on each stack, for particulate control.
4. Three (3) sets of multi-cyclone dust collector systems, one (1) for Boilers 1 and 2, and two (2) for Boiler 3. For Boiler 2, there is a new 2010 Barron Fan Technology, Inc. multi-cyclone.
5. 20,000 lb/hr Rotary Sugar Dryer with Entoleter Model 0405 wet scrubber.
6. The coal was previously supplied by Tivoli Coal Hawaii, which was imported from Australia. Also about 5,000 tons of low-sulfur bituminous coal has been purchased from the then non-operating Hu Honua Bioenergy, Pepeekeo Mill Power Plant, Big Island in early August 2009. The new 2011 proposed supplier of bituminous low sulfur coal will be the Twentymile Coal Company's Foidel Creek Mine located near Hayden, Colorado.
7. Boilers 1 & 2 use (share) the same stack

Standard Industrial Classification Code (SICC)
2061 Cane Sugar & 4911 Electrical Services

Responsible Official: **Ms. Anna M. Skrobecki**
Senior Vice President, Factory Operations
(808) 877-6950

Mailing Address: P.O. Box 266
Puunene, Maui, HI 96784

Contact Persons:	Sean O'Keefe Director, Environmental Affairs Alexander & Baldwin
Mailing Address:	P.O. Box 266 Puunene, Maui 96784
Phone:	(808) 877-2959
Cell:	283-8907
Fx:	(808) 871-7663
Email:	sokeefe@hcsugar.com

BACKGROUND

Hawaiian Commercial & Sugar (HC&S) Company operates a sugar cane cleaning and processing facility in Puunene, Maui, Hawaii. The Puunene Sugar Mill is located on a 30-acre site bounded by Hansen Road to the north and Puunene Avenue to the west. The facility is approximately 75 feet above sea level and the land surrounding the mill is primarily used for growing sugar cane. The Puunene Sugar Mill currently operates under the following air permits:

1. Authority to Construct (ATC) A-1128-1042, issued on November 2, 1993 for Burning of Coal in Existing Bagasse Boilers Nos. 1 and 2. In this ATC, the phrase "when burning coal (providing 90 percent or more of the total heat input)" was developed.

2. Amendment to Permit to Operate (PTO) P-783-1586, issued on August 11, 2003 for 100% Wet Scrubber, Partial Hopper Evacuation, and Modified Multicyclone for Bagasse/Oil-Fired Boilers 1 & 2, and 75,000 ton/yr Sugar Dryer with Entoleter Model 0405 Wet Scrubber

3. Permit to Operate (PTO) No. P-605-1584, issued on October 13, 1993 for Burning of Coal in the 568 MMB/hr Bagasse Boiler No. 3

4. Permit to Operate (PTO) No. P-40-1585, issued on October 18, 1993 for Operation of 568 MMBtu/Hr. Bagasse Boiler No. 3 with Multicyclones and 100% Wet Scrubber System.

Equipment at the Puunene sugar mill consists of sugar cane cleaning and processing equipment, storage and handling equipment, steam and electrical processing equipment, maintenance and repair equipment, and miscellaneous emergency and support equipment. While processing sugar cane, the Puunene sugar mill operates two (2) Riley Stoker boilers and one (1) Foster Wheeler boiler and with a capacity to generate a total steam output of 540,000 lb/hr and to produce approximately 46 MW of electric power some of which is sold to Maui Electric Company.

The boilers are permitted to burning bagasse (sugar cane fiber), untreated wood chips, banna grass, distillate fuel oil no. 2, coal, and small quantities of agricultural material, consisting of flowers, foliage, fruits and vegetables in cardboard boxes. Used cooking oil and used lubricating oil/transformer oil is also burned in the boilers. The applicant is permitted to burn used oil generated from their own facility, and the sulfur content of this oil shall be less than 0.5% by weight, in Boiler 3. The applicant is also permitted to burn used oil purchased from commercial sources, with the sulfur content of this source of oil below 0.75%. The used oil must be laboratory tested prior to burning to demonstrate that it meets specification used oil requirements. The 3 boilers all together were permitted to burn 1,500,000 gallons of specification used oil per calendar year, with each boiler recording the amount of used oil burned. With the issuance of this permit, the amount of used oil will be 2,000,000 gallons per rolling twelve (12) month basis.

The total amount of coal fired in Boilers 1 and 2 shall not exceed 62,606 tons as measured on a rolling twelve month basis. The amount of coal fired in Boiler 3 shall not exceed 45,000 tons as measured on a twelve month rolling basis.

Other fuels, including other biomass fuel, may be fired in the boilers provided prior written approval is granted by the Department of Health (DOH).

The three (3) boilers were classified as biomass boilers, and therefore previously each boiler must have at least 50% of its annual heat input provided by biomass. HAR Subchapter 1, §11-60.1-1 defines "biomass fuel burning boilers" as fuel burning equipment in which the actual heat input of biomass fuel exceeds the actual heat input of fossil fuels on an annual basis. HC& S requested to remove the "biomass labels". The DOH removed the biomass labels, but kept the biomass requirements for Boiler 3 because burning more than 50 percent of bagasse annually was a major factor in the permittee's request for an alternate sulfur dioxide CEMS procedure for Boiler 3 while burning fuel oil and coal, also Puunene Mill's maximum potential to emit pollutant emissions and the Mill's ambient air quality assessment that were submitted are also based on the 50 percent biomass classification.

In an April 8, 2003 letter, HC&S requested an Alternate Fuel Sampling Analysis in lieu (in place) of continuous emissions monitoring system (CEMS) for sulfur dioxide while burning coal. The following sentence was taken from the April 8 letter, *"Since 85% of Boiler 3's heat input came from firing bagasse, and 15 % coming from fossil fuel, this lessens the need for a continuous monitoring system for sulfur dioxide when burning coal and fuel oil."*

The three (3) boilers are also classified as utility boilers. Utility boilers have heat input greater than 100 MMBtu/hr.

Boiler 3 has a heat input capacity greater than 250 million BTU per hour, and in accordance with HAR §11-60.1-38(b) is required to burn fuel with a total sulfur content, by weight, of less than 0.5%. Boilers 1 and 2, in compliance with HAR §11-60.1-38(a) shall not burn any fuel containing more than 2% sulfur content by weight.

The primary fuel for the boilers is bagasse, a biomass by-product of crushed sugar cane fiber waste remaining after processing. The bagasse is stockpiled at the facility and is burned in the boilers as needed. Since sugar cane processing is typically a seasonal operation, the facility is permitted to burn both fuel oil and coal as back-up fuels. Bagasse is normally stored in the bagasse house, but also may be piled in three (3) storage areas located behind the mill to a height not to exceed twenty (20) feet.

The back-up fuel is washed low sulfur coal that is stored in any of the three storage areas until needed at the coal supply pile. The coal is moved from the 20-feet high piles in the storage areas to the supply pile by truck. The coal supply is approximately 100 feet by 250 feet in size, with a maximum height of twenty (20) feet. Coal in the storage and supply piles are washed to minimize the formation of fugitive dust, and to maintain a moisture content of approximately 8 percent. Coal from the supply pile is fed directly into the boiler via a conveyor system.

In addition to the 3 boilers, PTO No. P-783-1586 was amended in February 2000 to operate a premium Turbinado 20,000 lb/hr rotary sugar dryer and cooler system with a Entoleter model 405 wet scrubber. This system is located upstream of the existing sugar packaging plant and improves the quality of specialty sugar production.

The stainless steel rotary dryer is thirty (30) feet long and five (5) feet in diameter, and is equipped with an Entoleter Model 0405 wet scrubber to capture sugar dust sucked in the dryer air flow. The dry sugar exits the dryer and enters the cooling tray, where ambient air is blown across the dry sugar to cool it prior to packaging. The exhaust from the cooler is routed to the wet scrubber. In the wet scrubber the air stream pass through water sprays which remove most of the particulate matter sucked in the stream of air. The scrubber air stream is routed via an induced graft fan to a fifty (50) feet exhaust stack.

The sugar dryer processing rate was limited to 13,680 tons on a rolling twelve-month (12-month) basis. The PTO was amended in August 2003 to allow up to 75,000 tons of premium sugar to be dried on a rolling twelve-month (12-month) basis. New net emissions from the sugar dryer are less than two (2) tons, so Prevention of Significant Deterioration (PSD) review is not triggered.

Six (6) years after submitting the initial title V permit (November 1994) application, the permitting process was delayed because the applicant determined that Boiler 3 is subject to 40 CFR Part 60, Subpart D, *Standards of Performance for Fossil-Fuel-Fired Stream Generators for Which Construction After August 17, 1971*. The Federal Regulation establishes emission limits for particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxides (NO_x), and also requires the installation and operation of a continuous opacity monitoring system (COMS) and a continuous emissions monitoring system (CEMS) for SO_2 and NO_x for Boiler 3.

Hawaiian Commercial and Sugar requested an alternate monitoring procedure in lieu (as a substitute) of CEMS on Boiler 3 for nitrogen oxide (NO_x) and sulfur dioxide (SO_2). HC&S felt that determining compliance with the NO_x emission limit could be accomplished by performing an annual source test on Boiler 3.

By keeping the sulfur content of Boiler 3 less than or equal to 0.5% by weight of the fuel, compliance with the SO_2 emission limit for liquid fuels, such as fuel oil no. 2, propane, and specification used oil, could be determined by fuel purchase receipts. Compliance with the SO_2 emission limit for solid fossil fuels could alternatively be done using the coal monitoring plan proposed by Hawaiian Commercial and Sugar. This plan was deemed acceptable only by U.S. EPA, Region 5, which represents the following coal producing states: Minnesota, Wisconsin, Illinois, Indiana, Ohio, and Michigan. U.S. EPA, Region 9, voiced its opposition to the coal monitoring plan, but did not provide any confirmation in writing.

Therefore, the overall results of having Boiler 3 subject to Federal New Source Performance Standards are:

- Initial Title V permit issuance has been significantly delayed.
- Emission limits established for PM, SO_2, and NO_x, but verification only by fuel monitoring (for SO_2), and annual source testing.
- Discontinued burning fuel oil no. 6 in all three (3) boilers.

On September 3, 2003, DOH issued the Respondent, HC&S, a Notice and Finding of Violation, alleging that Respondent violated EPA Title 40, Code of Federal Regulations (CFR) Part 60, Subpart D, Standard of Performance for Fossil-Fuel-Fired Steam Generators, by not operating the bagasse burning 568 MMBtu/hour Boiler 3 steam generator in compliance with the applicable standard mentioned above. HC&S, the Respondent, requested a hearing on September 10, 2003. Instead of a hearing, DOH issued a December 8, 2006 consent order and a fine to HC&S to resolve the violations of state regulations and federal regulations.

As part of the consent order, there is a two phase Supplemental Environmental Project (SEP). The first phase requires HC&S, in lieu of Continuous Opacity Monitoring System (COMS), to implement alternative opacity monitoring for Boilers 1 and 2:

1. Continuously monitor and record the sixty (60) minute rolling average of the liquid flow rate to the venturi wet scrubber. The venturi wet scrubber shall be operating at all times during operation of one or both boilers;
2. Continuously monitor and record the sixty minute rolling average of the pressure drop of gas stream across the venturi wet scrubber; and
3. For each month, conduct visual emissions evaluations (VEE) of the two-flue stack in accordance with Method 9 of 40 CFR Part 60, Appendix A. Two (2) consecutive six-minute observations shall be taken at fifteen (15) second intervals. The VEE may be done when both boilers are in operation, however is reasonable opportunity exist to test each boiler individually, the VEE shall be conducted on each boiler.

The Respondent did not follow through on Phase I. Reference to September 25, 2007, HC&S twenty-ninth Compliance Progress Report, *"SEP Phase I, appears to be invalidated since continuous monitoring of Boilers 1 and 2 venturi wet scrubber was to be required by Federal Regulations for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (ICI Boilers MACT). Since the ICI Boilers MACT was vacated and remanded by the U.S. Court of Appeals for the District of Columbia Circuit, it is unclear what regulatory requirements will apply to Boiler 1 and 2.* So the cost of Phase I will be incorporated into Phase II of the SEP.

Under Phase II of the proposed Supplemental Environmental Project (SEP) HC&S will make improvements to the existing mechanically controlled system on the bagasse feeder belt conveyor system that delivers "damp" bagasse fuel from the mill and/or bagasse house to Boiler 3. The proposed upgrades will impact only the system for delivering bagasse to the Boiler 3 feeders, in other words, from the conveyor system up to the chutes through which bagasses enters the feeders.

No changes will be made to the bagasse feeders to deliver fuel into Boiler 3. The rated capacity of the Boiler 3 and bagasse feeders will not be changed. The objective of the upgrades is to minimize impacts on Boiler 3 operations due to wet bagasse coming from the mill, which will reduce boiler upsets and the associated increase in visible emissions from all three (3) boilers.

The proposed revisions are:

- Firing additional fossil fuels with the wet bagasse;
- Diverting wet bagasse to the bagasse house and switching to firing fuel oil;
- Diverting wet bagasse from the mill to the bagasse house and burning bagasse from the bagasse house, or;
- Adding drier bagasse to mix with the wet bagasse.

The upgrades shall include the following:

1. HC&S shall have in place, operate and maintain a real-time moisture analyzer on the bagasse delivery conveyor between the mill and power plant, conveyor no. 6071, in order to provide advance warning to boiler operators of an increase in the moisture content of bagasse coming from the mill, preparing boiler operators to prevent malfunction of the delivery system rather than reacting to delays from poor combustion of bagasse;
2. The bagasse conveyor system shall be configured to allow a portion of the bagasse feed from the mill to bypass the boilers and discharge to the bagasse house, and to allow continuous bagasse feed from the bagasse house via the elevator belt conveyor 6078, to combine with bagasse from the mill, improving the overall consistency of bagasse fed to all three boilers from the feeder belt conveyor 6072;
3. Bagasse chutes for Boiler 3 shall extend to the return belt conveyor and shall be configured to allow bagasse to be fed to Boiler 3 via either the return belt conveyor 6072 or the feeder belt conveyor 6072;
4. Ploughs shall be installed on the return belt conveyor so that at least half of the Boiler 3 bagasse feeders are fed directly from the return belt conveyor; and
5. The bagasse conveyor system maybe operated with all three boilers being fed directly from the mill in the event that a system failure temporarily prevents feeding bagasse from the bagasse house.

Then in April 2009, the DOH confirmed that the EPA's MACT Hammer is applicable to HC&S's permit.

June 2007, the U.S. Court of Appeals vacated EPA's emission limits for the Industrial Boiler Category, Part 63 Subpart DDDDD-National Emission Standards for Hazardous Air Pollutants (HAPs) for Industrial, Commercial, and Institutional (ICI) Boilers and Process Heaters SOURCE: 69 FR 55253, Sept 13, 2004, unless otherwise noted.

Under Section 112(j), the hammer provisions, of the Clean Air Act, the responsibility for establishing the emission limits fall on the state's clean air agencies, which must set standards on a case-by-case basis, consistent with the statutory requirements that EPA was to follow. The law requires that the standards - known as Maximum Achievable Control Technology (MACT) standards – be based on an average of the best performing existing sources, and may not be less stringent than the MACT floor, defined as the best performing 12 percent of sources in the industrial category.

The Hawaii Department of Health (DOH) selected the "Reducing Hazardous Air Pollutants from Industrial Boilers: Model Permit Guidance" June 2008, published by the National Association of Clean Air Agencies (NACAA), to meet the requirements set by the Clean Air Act, Section 112(j), the MACT Hammer, to establish HAPs emission limits on HC&S's three boilers.

After completing a draft MACT Hammer permit, the Department of Health chose to have HC&S, the owner/operator of the boilers, review the draft. The owner/operator of the boilers responded that the DOH draft permit had pollutant emission limits based on type of fuel, whereas the future EPA MACT regulations will be based on boiler size. HC&S said they would have difficulty meeting the DOH MACT Hammer carbon monoxide, particulate matter, hydrogen chloride, and mercury emissions limitations. In fact, HC&S would have to shut down and close the electricity making business.
In April, 2010, after conferring with U.S. EPA, Region 9, the DOH decided to process the HC&S permit without the MACT Hammer HAPs emission limits on the three (3) boilers.

On February 21, 2011, EPA finalized this rule Docket ID No. [EPA-HQ-OAR-2002-0058; FRL-] RIN 2060-AQ25, that replaces 40 CFR Part 63, Subpart DDDDD, National Emission Standard for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Industrial Boilers and Process Heaters, that was vacated and remanded by the United States Court of Appeals for the District of Columbia Circuit on June 19, 2007. This new rule establishes emission standards that will require industrial, commercial, or institutional boilers and process heaters to meet hazardous air pollutant standards reflecting the application of maximum achievable control technology (MACT). This final rule is incorporated by reference in CSP No. 0054-01-C effective 60 days after the date of publication in the Federal Register.

PROCESS DESCRIPTION

The primary process at the HC&S facility is the production of raw sugar from sugar cane. Sugar cane is a large grass with a bamboo-like stalk that grows 8 to 15 feet tall. Only the stalk contains sufficient sucrose for processing into sugar. The cane is cleaned of extraneous material, leaves, top growth and roots, and delivered to the mill. At the mill, the raw cane is cleaned of trash and dirt, and chopped and crushed. Juice is extracted in the milling process by passing the chopped and crushed cane through a series of grooved rollers. The cane fiber remaining after milling is bagasse.

Reducing the juice requires a constant supply of steam, which is provided by the bagasse, coal and oil fired boilers. Bagasse is fed by conveyor to each boiler through a fuel chute and is spread evenly across the grate. Bagasse has a high moisture content, typically 45 to 55%, and much of the moisture is released while the bagasse is in suspension. The dried bagasse continues to burn in an even layer on the moving grate which empties to an ash hopper in the boiler.

Each boiler also has a dual fuel feeder system which can operate on either bagasse or coal. Bagasse is fed by conveyor to the bagasse feeders. Excess bagasse is returned to the bagasse house where it is recycled. Coal is likewise fed to the coal feeders by conveyor. Excess coal is deposited into bins and returned to the coal storage pile. Coal has been imported from Australia and purchased from the Pepeekeo Power Plant on the Big Island.

Auxiliary fuels, coal, specification used oil, and no. 2 distillate oil , are used in all three boilers when the bagasse has a moisture content too high to support combustion, or when bagasse is not available due to mill upsets or shutdowns, or during the bagasse off-season from late November through early March.

All three (3) boiler’s oil burner startup is done with propane. Each boiler is equipped with a propane igniter. In Boilers 1 and 2, each of the four (4) burner igniters on each boiler is rated at

237,500 BTU/hr. The control circuitry prevents the igniters from firing continuously. When the igniters are fired, they trip off after 30 seconds, regardless of whether the burners have ignited. This off procedure protects the igniters from damage. They are designed for continuous firing. Once the igniters have tripped off, they cannot be fired again for another 90 seconds. It is therefore not possible to burn for more than fifteen (15) minutes of every hour. The effective rating of each igniter is one-fourth of 237,500 BTU/hr or 59,375 BTU/hr.

Each of the four (4) propane igniters on Boiler 3 Cohen burners is rated at 300,000 BTU/hr. Also by control circuitry, which restricts operations to thirty (30) seconds in every two-minute (2-minute) period, results in rates for each igniter to one-fourth of 300,000 BTU/hr, or 75,000 BTU/hr. The maximum potential to emit for all of the propane igniters is less than one (1) ton per year. So in accordance with Hawaii Administrative Rules (HAR) 11-60.1-62(d)(1), the propane igniters are exempt from the Hawaii air permit requirement.

The boilers supply steam to provide pressure to turn the turbine generators. The steam enters on one end of the turbine. It expands as it rushes through the turbine, spinning the turbine wheels. The turbine generators provide electricity. There are three (3) turbine generators. Unlike a utility power plant, the turbines are not necessarily dedicated to one specific boiler. For example, the steam from Boilers 1 and 2 can be supplied to any of the turbines and Boiler 3 can supply steam to two (2) of the turbines.

One turbine generator is provided with steam from a high pressure, 900 psig, steam header that can only be supplied by Boilers 1 and 2. A second turbine generator is provided with steam from a lower pressure, 450 psig, steam header that is normally supplied by Boiler 3. The third turbine generator is normally kept as a backup and is also provided with steam from the lower pressure, 450 psig, steam header. The lower steam header can also be supplied by Boilers 1 and 2.

Operational limits on the boilers' fuels are summarized below:

TABLE 2 – 3 BOILERS FUEL		
FUEL DESCRIPTION	BOILER 3	BOILER 1&2
Sulfur Content	Fuel Oil no. 2 & Coal Less than 0.5% by Wt Spec Used Oil (See TABLE 3 Below)	Coal Less Than 0.5% by Wt Spec Used Oil (See TABLE 3 Below)
Coal	Max Thruput: 45,000 ton/yr	Max Thruput: 62,606 ton/yr
Biomass	Min Biomass BTU = BQF X Potential Heat Input	
Spec Used Oil	Maximum 2,000,000 gal per Rolling 12-Month Commercial and In-House Sources See Constituent Limits in TABLE 3 Below	

TABLE 3 SPECIFICATION USED OIL ALLOWABLE LIMITS	
CONSTITUENT/PROPERTY	ALLOWABLE LIMIT
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1,000 ppm maximum
Sulfur	0.5% Boiler 3 In-house only 0.75% Boiler 1 and 2 Commercial Source
Flash Point	100 ° F minimum
PCB	Less than 2 ppm

THE APPLICANT'S REQUESTS

For Boiler 3, which is subject to 40 CFR Part 60 Subpart D, §60.45 Emission and Fuel Monitoring.

§60.45(a) Each owner or operator shall install, calibrate, maintain, and operate continuous opacity monitoring systems (COMS) for measuring opacity and a continuous emissions monitoring systems (CEMS) for measuring emissions of sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide. The applicant, HC&S, has requested the following 5 issues:

1. On March 8, 2002 and April 8, 2003, HC&S submitted a Request for an Alternate Procedure of COMS for Boiler 3.

    a. Conduct at least two (2) consecutive six-minute (6-minute) visual emissions evaluations (VEE) on Stack 2 in accordance with 40 CFR Part 60, Appendix A, Method 9. Monthly VEE shall be conducted, recorded, and reported to the Department of Health;
    b. Monitoring devices shall be installed, operated, maintained, and calibrated such that representative measurements of scrubber operating parameters are obtained. The range of the monitoring devices shall be sufficient to measure the minimum and maximum operating values of the wet scrubber parameters and easy to read;
    c. Except for system breakdowns, repairs, calibrations checks, and zero span adjustments, equipment for monitoring and recording scrubber liquid flow rate and venturi pressure drop shall be in continuous operation; and
    d. The one-hour (1-hour) average of scrubber operating parameters shall be running 60-minute average and shall be determined from a minimum of ten or more data points equally spaced over each sixty-minute (60-minute) period. Data collected during periods of continuous equipment breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed.
    e. A quality assurance and control plan shall be developed to verify that the monitoring devices are generating quality assured data. The monitoring devices shall meet appropriate American Society of Mechanical Engineers (ASME) or other applicable specifications.

The Venturi Wet Scrubber servicing Boiler 3 operates in either the “recirculation” mode or in the “once through” mode.

In the recirculation mode, water passing through the wet scrubber is constantly recirculated and reused except for a small percentage of blowdown that is discharged to the millwater system to prevent accumulation of solids in the scrubber water. Clean makeup water is added as necessary to replace water lost through blowdown or evaporation. This mode is intended to minimize the amount of wastewater generated by the wet scrubber and is the normal operating mode.

The once-through mode, water passing through the wet scrubber is used only once and then is discharged to the millwater system for disposal. This mode is used only during malfunctions or maintenance of the recirculation system, or during off-season when wastewater minimization is less of an issue.

2. The July 1, 2005 revision of the April 8, 2003 submittal, requested in lieu of (in place of) CEMS for measuring sulfur dioxides, a fuel sampling and analysis (FSA) procedure for coal. The HC&S “Proposed Procedures” cites EPA Region 5’s approved fuel sulfur analysis 40 CFR Part 60, Appendix A-7, Reference Method 19 – Determination of Sulfur Dioxide Removal Efficiency and Particulate, Sulfur Dioxide, and Nitrogen Oxides Emission Rates, §12.5.2.1 Solid Fossil (Including Waste) Fuel/Sampling and Analysis, as an alternative method for continuous emissions monitoring system (CEMS), to determine the sulfur content in coal and also to determine sulfur dioxide emissions from HC&S’s Boiler 3 while burning coal.

   April 8, 2003, HC&S, citing 40 CFR §60.45(b)(2) *“For a fossil-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis,”* requested in place of CEMS, an alternate fuel sample analysis (FSA) for sulfur dioxide while burning coal.

   During a September pre-draft permit review with the applicant, HC&S, it was brought to the DOH’s attention that HC&S has not finalized or secured contracts nor procured equipment for the FSA mentioned above because the applicant’s request for alternate COMS and CEMS submittals were never approved by the DOH. The applicant requested to submit another revised (the third revision) alternate FSA for sulfur dioxide while burning coal.

3. September 14, 2005, HC&S requested approval for manual processing of the coal primary sampler instead of the automatic processing as submitted in the July 1, 2005 revision of the April 8, 2003 request.

4. April 8, 2003, HC&S, citing 40 CFR §60.45(b)(2) *“For a fossile-fuel-fired steam generator that does not use a flue gas desulfurization device, a CEMS for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis,”* requested in place of CEMS, a fuel sampling and analysis procedure for fuel oil referencing 40 CFR Part 75, Appendix D. The Hawaii Department of Health did not approve use of the procedure given in Part 75 Appendix D.

   The applicant submitted a letter dated April 8, 2003, “Request for Approval of Alternative to CEMS Requirements”. Beginning with the second to the last line on page 6 through the first line on page 7 of the April 8th letter, “*Boiler 3 is a biomass fuel boiling boiler, with the vast* *majority of heat input (about 78% in 2002) coming from firing bagasse fuel. During most of the year, Boiler 3, is operated on bagasse as the primary fuel.*

The following sentence was taken from the last line of the third paragraph on the same page 7 referenced above, "*In the attached examples the NSPS compliance calculation for NO_x is shown based on the assumption that the boiler is fired with 85% of the heat input coming from bagasse, and 15% coming from fossile fuel, a typical operating scenario.*"

The DOH, by deduction of the contents of the above letter, derived that specification used oil will be an additive along with fuel oil no. 2 to coal (comprising 15 -22%) of Boiler 3's fuel, and bagasse (comprising 85-78%) of Boiler 3's fuel .

5. Also in the April 8, 2003 letter, HC&S requests DOH's approval for another exemption from the CEMS requirement for nitrogen oxide while burning coal.

   In accordance to 40 CFR Part 60, Subpart D, §60.45(b)(3), *"Notwithstanding §60.13(b), installation of a CEMS for nitrogen oxides may be delayed until after initial performance test under CFR §60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in CFR §60.44, a continuous emissions monitoring system (CEMS) for measuring nitrogen oxides is not required" at this time and date. If the initial performance test results show that nitrogen oxide emissions are* <u>greater than</u> *70 percent of the applicable standard, the owner or operator shall install a CEMS for nitrogen oxides within one year after the date of the initial performance test under §60.8 and comply with all other applicable monitoring requirements under this part.*

   On all sources applicable to the Code of Federal Regulations (CFR), the Department of Health has no authority to accept requests from the owners of the source for alternate procedures in place of COMS or CEMS. So all COMS and CEMS as specified in CFR Part 60, Subpart D, §60.45(a) are required for Boiler 3 in the initial issuance of this permit. Request for alternate COMS and CEMS monitoring procedures, must be submitted to the Administrator of U.S.EPA, Region 9.

   Semi-annual reporting and annual reporting using the DOH's "Boiler 3 Excess Emissions and Monitoring System Performance Summary Report Form" for the above mentioned COMS and CEMS shall be required to monitor and record opacity and nitrogen oxides and sulfur dioxide emissions and shall be submitted to the DOH and to the Regional Administrator, U.S. EPA, Region 9.

ENVIRONMENTAL PROTECTION AGENCY (EPA) REGION 9, AIR STANDARD DELEGATION. SPECIFIC AUTHORITIES RETAINED BY EPA.

In general, EPA does not delegate to state or local agencies the authority to make decisions that are likely to be nationally significant, or alter the stringency of the underlying federal standards. As additional assurance of national consistency, state and local agencies must send to U.S. EPA, Region 9, Air Division's Enforcement Office Chief, a copy of any written decisions made pursuant to the following delegated authorities:

1. Applicability determinations that state a source is not subject to a rule or requirement;
2. Approvals or determinations of construction, reconstruction or modification;

3. Minor or intermediate site-specific changes to test methods or monitoring requirements; or
4. Site-specific changes or waivers of performance testing requirements.

40 CFR Part 60 New Source Performance Standards (NSPS)

The following provisions of Subpart A are not delegated:

Specification sections §60.4(b), 60.8(b), 60.9, 60.11(b), 60.11(e), 60.13(a), 60.13(d)(2), 60.13(g), and 60.13(i);

Subpart B and Subpart C (NSPS Subparts Ca-Ce) have not been delegated to state and local agencies.

40 CFR Part 61 National Emission Standards For Hazardous Air Pollutants (NESHAP)

The following provisions of Subpart A are not delegated:

Specification sections §61.04(b), 61.04(c), 61.05(c), 61.11, 6.12(d), 61.13(h)(1)(ii), 61.14(d), 61.14(g)(1)(ii), and 61.16.

40 CFR Part 63 NESHAP, For Source Categories (MACT Standards)

The following provisions of Subpart A are not delegated:

1. Specification section §63.6(g), Approval of Alternative Non-Opacity Emission Standards;
2. Specification section §63.6(h)(9), Approval of Alternative Opacity Standards;
3. § 63.7(e)(2)(ii) and (f), Approval of Major Alternative To Test Methods;
4. § 63.8(f), Approval of Major Alternative To Monitoring;
5. § 63.10(f), Approval of Major Alternatives To Recordkeeping and Reporting;
6. Plus any other provisions specifically identified as non-delegable in each individual standard.

Subpart B, C, D, and E are not delegated to state and local agencies

APPLICABLE REQUIREMENTS

Hawaii Administrative Rules (HAR) Title 11
Chapter 11-59, Ambient Air Quality Standards
Chapter 11-60.1, Air Pollution Control
- Subchapter 1, General Requirements
- Subchapter 2, General Prohibitions
  - 11-60.1-32, Visible Emissions
  - 11-60.1-33, Fugitive Dust
  - 11-60.1-36, Biomass Fuel Burning Boilers
  - 11-60.1-38, Sulfur Dioxides from Fuel Combustion
- Subchapter 5, Covered Sources
- Subchapter 6, Fees for Covered Sources, Noncovered Sources, and Agricultural Burning
- Subchapter 8, Standards of Performance for Stationary Sources
- Subchapter 9, Hazardous Air Pollutant Sources
- Subchapter 10, Field Citations

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES also known as NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR Part 60 Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971.

Boiler 3 is subject to 40 CFR 60 Subpart D because Boiler 3 is a fossil-fuel-fired steam generating unit of more than 250 million British thermal units per hour (MMBtu/hr). See page 2, Table 1, Boiler 3, Rating Heat Input, of this review, for Boiler 3's heat input rating while burning bagasse, coal and fuel oil. This standard does not apply to Boilers 1 and 2 because construction of the boilers began in 1957, before this standard was placed into effect as a federal law, and both boilers have individual heat input of less than 250 MMBtu/hr.

TITLE 40 CODE OF FEDERAL REGULATIONS (CFR) PART 60 SUBPART D, §60.41 DEFINITIONS

All terms not defined herein shall have the meaning given them in the Clean Air Act, and in Title 40 Code of Federal Regulations (CFR) Part 60 Subpart A.

Boiler operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted during the entire 24-hour period.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by ASTM D388 (incorporated by reference, see 40 CFR§60.17).

Coal refuse means waste-products of coal mining, cleaning, and coal preparation operations (for example culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

Fossil fuel and wood residue-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

Fossil-fuel-fired steam generating unit means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

Wood residue means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS) FOR SOURCE CATEGORIES MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT)

MACT means the maximum degree of reduction in emissions of the hazardous air pollutants (HAPs), on a case-by-case basis, taking into consideration the cost of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements that is deemed achievable.

In accordance with HAR §11-60.1-1 Definitions, a "major source of HAPs" is defined as a source or a group of stationary sources that is located on one or more contiguous or adjacent properties, and is under common control of the same person, or persons under common control, and that emits or has the potential to emit considering controls and fugitive emissions, any HAP, except radionuclides, in aggregate of ten (10) tons per year or more or twenty-five (25) tons per year or more of any combination of HAPs.

40 CFR Part 63, MACT has been vacated or annulled by the federal courts for Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The three (3) Puunene Sugar Mill boilers are major sources of HAPS when burning bagasse and will be subject to a new MACT standard presently being revised and rewritten by EPA.

The EPA Part 63 Subpart DDDDD Standard will go into effect 60 days after it is published in the Federal Register. A modification application will be due 90-days after the published date of the standard. Owners of the equipment applicable to this new Federal Regulation will have three (3) years to bring their boiler(s) or heaters into compliance.

COMPLIANCE ASSISTANCE MONITORING (CAM)

40 CFR Part 64 applies to large emission major sources that rely on air pollution control devices to achieve compliance. HAR 11-60.1 Subchapter 1 §11-60.1-1 defines a major source as a source or a group of stationary sources that is located on one or more contiguous or adjacent properties and is under common control of the same person or persons belonging to a single major industrial grouping, that is, having the same two-digit Standard Industrial Classification Code (SICC) and emits or has the potential to emit, considering controls, one hundred tons per year or more of any air pollutant. Applicability of the CAM Rule is determined on a pollutant specific basis for each affected emission unit. Each determination is based upon a series of evaluation criteria. In order for a source to be subject to CAM, the facility must meet all the following criteria:

1. Be a major stationary source per Title V of the Clean Air Act Amendments of 1990; Yes
2. Be subject to federally enforceable applicable requirements or standard? Yes.
3. Have pre-control device potential emissions that exceed applicable major source thresholds? Yes.
4. Be fitted with an active air pollution control device? Yes.
5. Not be subject to certain regulations that specifically exempt the facility from CAM? Yes.
6. Did not complete Title V application prior to April 20, 1998? Yes, the HC&S file folder has a submitted letter dated July 29, 1999, requesting to revise AAQS analysis for the initial 1994 application by August 6, 1999.

   This application review also found a September 10, 1999 DOH letter notifying HC&S that the AAQS analysis of the 1994 application was done with 50% of boilers emission rates.

   This application review also found a December 17, 2002 DOH letter, notifying HC&S, that pursuant to the deregulation agreement with EPA, an alternate procedure in place of COMS that was requested by HC&S has been forwarded to EPA for a determination

In accordance with 40 CFR Part 64, CAM will apply to the three (3) boilers on the renewal of this permit.

The CAM Plan shall:

1. Describe the indicators to be monitored and how they are to be measured;
2. Describe the indicator ranges or the process by which indicators are to be established;
3. Describe the performance criteria for the monitoring approach including:

    a. Specifications for obtaining representative data;
    b. Quality assurance and control procedures;
    c. Monitoring frequency;
    d. Data collection procedure; and
    e. Data averaging period;

4. Provide justification for the proposed elements of the monitoring;
5. Provide historical monitoring data, emissions test data and control device operating data recorded during performance test;
6. Provide an implementation plan for monitoring installation, testing, or other activities prior to installation;
7. Provide a Quality Improvement Plan (QIP).

<u>Consolidated Emissions Reporting Rule **(**CERR</u>)
40 CFR Part 51, Subpart A - Emission Inventory Reporting Requirements. CERR is established to simplify reporting, offer options for data collection and exchange, and unify reporting dates for various categories of criteria pollutant emission inventory, for example, point, area, onroad, and nonroad mobile, and biogenics.

Emission inventories are critical for federal, state, and local agencies to attain and maintain the national ambient air quality standards (NAAQS), projecting future control strategies, tracking progress to meet requirements of the Clean Air Act (CAA), calculating risk, and responding to public inquiries.

This rule applies to state and local agencies. CERR is based on plant-wide emissions of each air pollutant that emits at or exceeds the CERR triggering levels shown in the table below.

TABLE 4
MAXIMUM EMISSIONS COMPARED to SIGNIFICANT LEVELS and CERR THRESHOLDS (tpy)

POLLUTANT	PLANT-WIDE EMISSIONS	SIGNIFICANT LEVELS	CERR TRIGGERING LEVELS	
			1-YEAR CYCLE (TYPE A SOURCES)	3-YEAR CYCLE (TYPE B SOURCES)
NOx	1,560	40	≥ 2500	≥ 100
CO	11,590	100	≥ 2500	≥ 1000
SO_2	1,410	40	≥ 2500	≥ 100
PM-10	690	15	≥ 250	≥ 100
VOC	470	40	≥ 250	≥ 100
HAPs	170	--	--	--

Plant-Wide emissions are based on facility operating 8,760 hr/yr.
Symbol “≥” stands for “greater than or equal to”.

Facility emissions exceeds CERR triggering levels, therefore, the permittee is subject to the CERR requirement. As given above, nitrogen oxides shall be reported in 3-year cycles, carbon monoxides shall be reported every year and in 3-year cycles, sulfur dioxide shall be reported in 3-year cycles, particulate matter as particles with an aerodynamic diameter less than or equal to a nominal 10 micrometers, shall be reported as an annual inventory and in 3-year inventories, volatile organic compounds shall be reported annually and triennially, and hazardous air pollutants shall be reported annually.

The Clean Air Branch requests annual emissions reporting from all covered sources.

<u>National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE-NESHAPs)</u>
40 CFR Part 63, Subpart ZZZZ is applicable to a stationary RICE with a site rating of less than or equal to 500 brake horse power located at a major source of HAPs emissions. A stationary RICE is *"existing"* if the source commenced construction or reconstruction of the stationary RICE before June 12, 2006. An existing stationary CI (compression ignition) RICE with a site rating less than or equal to 500 hp located at a major source of HAPs, must be in compliance with the applicable emission limits of this subpart by May 3, 2013. This is an existing source, where construction began before June 12, 2006, and, all the engines at the Puunene Sugar Mill were built before 2006, so all the diesel engines and one (1) diesel engine generator must be in compliance of the applicable limits noted in the permit by May 3, 2013.

For our records a SI is a "spark ignition" engine. A spark ignition engine burns gasoline.

<u>Greenhouse Gas Tailoring Rule,</u>
<u>Prevention of Significant Deterioration (PSD) and Title V Operating Permit</u>

Under the Clean Air Act (CAA) permitting program, the U.S. Environmental Protection Agency (EPA) issued a final Greenhouse Gas Tailoring Rule. This rule sets thresholds for greenhouse gas (GHG) emissions that define when permits under the New Source Review Prevention of Significant Deterioration (PSD) and Title V operating permits programs are required for new or existing industrial facilities.

This rule "tailors" the requirements of CAA permitting programs to determine which facilities will be required to obtain PSD and Title V permits.

The six (6) GHGs are:

1. carbon dioxide (CO_2)	4. Hydofluorocarbons HFCs)
2. methane (CH_4)	5. Perfluorocarbons (PFCs)
3. nitrous oxides (N_2O)	6. Sulfur hexafluoride (SF_6)

The total GHG emissions shall be calculated by summing the CO_2e of all six constituent GHGs. The international standard practice is to express GHGs in carbon dioxide equivalents (CO_2e). Emissions of the gases are translated into CO_2e by using the gases' global warming potentials.

To calculate GHG emissions for comparison to the 75,000 tons CO_2e per year emission threshold in Step 1 below, the permittee shall calculate annual CO_2e emissions, as described in (i) through (iv) below.

(i) Calculate the annual emissions of CO_2, CH_4, N_2O, and each fluorinated GHG in tons per year from all applicable source categories. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed above.

(ii) For each general stationary fuel combustion unit, calculate the annual CO_2 emissions in tons per year. Calculate the annual CH_4 and N_2O emissions from the stationary fuel combustion sources in tons per year. Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH_4 and N_2O from biomass combustion.

(iii) For miscellaneous uses of carbonate, calculate the annual CO_2 emissions in tons per year.

GWP_i = Global warming potential for each greenhouse gas from Table A–1 of CFR Part 98.1, are listed below in Table 5.

TABLE 5 – GLOBAL WARMING POTENTIAL (GWP)	
GREENHOUSE GAS	GWP
Carbon Dioxide (CO_2):	1
Methane (CH_4)	21
Nitrous Oxides (N_2O):	310
Hydofluorocarbons HFCs):	140 to over 11,700
Perfluorocarbons (PFCs)	5,210 to 9,200
Sulfur Hexafluoride (SF_6)	23,900

Biogenic CO_2 means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required by an applicable CFR Part 98.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals or micro-organisms, including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

Schedule

The annual GHG report for reporting year 2010 must be submitted no later than September 30, 2011. The annual report for reporting years 2011 and beyond must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year. As an example, for a facility or supplier that is subject to the rule in calendar year 2011, the annual report must be submitted on March 31, 2012.

Step 1. January 1, 2011 to June 30, 2011

A. Only sources currently subject to the PSD permitting program, those that newly constructed or modified in a way that significantly increases emissions of a pollutant other than the GHGs are subject to permitting requirements for their GHG emissions under PSD.

B. GHG emission increases of 75,000 tpy or more of total GHG, on a CO_2e basis, would need to determine the Best Available Control Technology (BACT) for their GHG emissions.

C. Similarly for the operating permit program, only sources currently subject to the program, that is, newly constructed or existing major sources for a pollutant other than GHGs would be subject to the Title V requirements fo GHG.

D. At this time, no sources would be subject to Clean Air Act permitting requirements due solely to GHG emissions.

Step 2. July 1, 2011 to June 30, 2013

A. PSD permitting requirements will apply to new construction projects that emit GHG emissions of at least 100,000 tons per year (tpy) even if the stationary source does not exceed any other pollutants permitting triggering value. Modifications at existing stationary sources that increase GHG emissions by at least 75,000 tpy shall be subject to permitting requirements, regardless if the stationary source does not significantly increase emissions of any other pollutant.

B. Operating permit requirements, for the first time, shall apply to sources based on their GHG emissions even if the stationary source would not apply based on emissions of any other pollutant. Stationary sources that emit 100,000 tpy or more of CO_2e shall be subject to Title V permitting requirements.

Calculations
40 CFR Part 98 Subpart C Table C-1 Default Carbon Dioxide Emission Factors
40 CFR Part 98 Subpart C Table C-2 Default Methane and
Nitrous Oxides Emission factors

See step-by-step calculations presented in 2-tables for Boilers 1 and 2 and

2-tables for Boiler 3 for greenhouse gases emissions are in the last section of the applicant's application.

PROPOSED

The annual greenhouse gases emissions are shown below.

TABLE 6

HC&S Greenhouse Gas Emissions (Mg/yr)

	Carbon Dioxide	Methane	Nitrous Oxide	CO_2 e
	Highest Overall GHG Emissions – 100% Biomass – Burning Bagasse			
Boilers 1 and 2	438,912	59	8	442,578
Boiler 3	587,976	159	21	597,798
Total	1,026,888	219	29	1,040,376
Total Biogenic	1,026,888	219	29	1,040,376
Total Excluding Biogenic CO_2	0	219	29	247
	Highest GHG – Fossil Fuel Burning Boilers 1 & 2 Burning Bagasse, Oil, and Coal Boiler 3 Burning Bagasse and Coal			
Boilers 1 and 2	353,828	69	9	358,202
Boiler 3	490,550	131	17	498,696
Total	844,377	201	27	856,898
Total biogenic	451,049	177	23	458,584
Total Excluding Biogenic CO_2	393,328	201	27	393,556

40 CFR Part 60 Appendix B – Performance Specifications

Performance Specification 1—Specifications and Test Procedures for Continuous Opacity Monitoring Systems in Stationary Sources

Performance Specification 1 (PS–1) provides (1) requirements for the design, performance, and installation of a continuous opacity monitoring system (COMS) and (2) data computation procedures for evaluating the acceptability of a COMS. It specifies activities for two groups (1) the owner or operator and (2) the opacity monitor manufacturer.

Measurement Parameter. PS–1 covers the instrumental measurement of opacity caused by attenuation of projected light due to absorption and scatter of the light by particulate matter in the effluent gas stream.

All definitions and discussions from section 3 of ASTM D 6216–98 are applicable to PS–1.

Centroid Area. A concentric area that is geometrically similar to the stack or duct cross-section and is no greater than 1 percent of the stack or duct cross-sectional area.

Data Recorder. That portion of the installed COMS that provides a permanent record of the opacity monitor output in terms of opacity. The data recorder may include automatic data reduction capabilities.

External Audit Device. The inherent design, equipment, or accommodation of the opacity monitor allowing the independent assessment of the COMS's calibration and operation.

Full Scale. The maximum data display output of the COMS. For purposes of recordkeeping and reporting, full scale will be greater than 80 percent opacity.

Operational Test Period. A period of time (168 hours) during which the COMS is expected to operate within the established performance specifications without any unscheduled maintenance, repair, or adjustment.

Primary Attenuators. Those devices (glass or grid filter that reduce the transmission of light) calibrated according to procedures in section 7.1.

Secondary Attenuators. Those devices (glass or grid filter that reduce the transmission of light) calibrated against primary attenuators according to procedures in section 7.2.

System Response Time. The amount of time the COMS takes to display 95 percent of a step change in opacity on the COMS data recorder.

Performance Specification 2 – Specifications and Test Procedures For SO_2 and NO_X Continuous Monitoring Systems in Stationary Sources

This specification is for evaluating the acceptability of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) continuous emissions monitoring systems (CEMS) at the time of installation or soon after and whenever specified in the CFR. The CEMS may include, for certain stationary sources, a diluent oxygen (O_2) or carbon dioxide (CO_2) monitor.

This specification also includes procedures for measuring CEMS relative accuracy and calibration drift outlined. CEMS installation and measurement location specifications, equipment specifications and performance specifications, and data reduction procedures are established to evaluate conformance.

Definitions

Calibration Drift (CD) means the difference in the CEMS output readings from the established reference value after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place.

Centroidal Area means a concentric area that is geometrically similar to the stack or duct cross section and is no greater than l percent of the stack or duct cross-sectional area.

Continuous Emission Monitoring System means the total equipment required for the determination of a gas concentration or emission rate. The sample interface, pollutant analyzer, diluent analyzer, and data recorder are the major subsystems of the CEMS.

Data Recorder means that portion of the CEMS that provides a permanent record of the analyzer output. The data recorder may include automatic data reduction capabilities.

Diluent Analyzer means that portion of the CEMS that senses the diluent gas (*that is.*, CO_2 or O_2) and generates an output proportional to the gas concentration.

Path CEMS means a CEMS that measures the gas concentration along a path greater than 10 percent of the equivalent diameter of the stack or duct cross section.

Point CEMS means a CEMS that measures the gas concentration either at a single point or along a path equal to or less than 10 percent of the equivalent diameter of the stack or duct cross section.

Pollutant Analyzer means that portion of the CEMS that senses the pollutant gas and generates an output proportional to the gas concentration.

Relative Accuracy (RA) means the absolute mean difference between the gas concentration or emission rate determined by the CEMS and the value determined by the reference method (RM), plus the 2.5 percent error confidence coefficient of a series of tests, divided by the mean of the RM tests or the applicable emission limit.

Sample Interface means that portion of the CEMS used for one or more of the following: sample acquisition, sample delivery, sample conditioning, or protection of the monitor from the effects of the stack effluent.

Span Value means the concentration specified for the affected source category in an applicable subpart of the regulations that is used to set the calibration gas concentration and in determining calibration drift.

NON APPLICABLE REQUIREMENTS

NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)
40 CFR Part 61 §61.01 lists the substances that have been designated as HAPs. NESHAPS is not applicable because although the HAPs are listed, the process or production which heats the boilers are not listed as a standard in this Subpart.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
40 CFR Part 52, §52.21, PSD review is a state implementation plan that applies to new major statuary sources and major modifications to sources listed and defined in HAR, Title 11, Chapter 11-60.1, Subchapter 7.

What is PSD's Purpose?

PSD does not prevent sources from increasing emissions. Instead, PSD is designed to:

1. Protect public health and welfare;

2. Preserve, protect, and enhance the air quality in national parks, national wilderness areas, national monuments, national seashores, and other areas of special national or regional natural, recreational, scenic, or historic value;

3. Insure that economic growth will occur in a manner consistent with the preservation of existing clean air resources; and

4. Assure that any decision to permit increased air pollution in any area to which this section applies is made only after careful evaluation of all the consequences of such a decision and after adequate procedural opportunities for <u>informed public participation</u> in the decision making process.

What is PSD Increment?

PSD increment is the amount of pollution an area is allowed to increase. PSD increments prevent the air quality in clean areas from deteriorating to the level set by the National Ambient Air Quality Standard (NAAQS). The NAAQS is a maximum allowable concentration "ceiling." A PSD increment, on the other hand, is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

Although the facility is a major stationary source of pollution, PSD regulations do not apply until a significant modification is performed on the facility because the boilers have been in existence and operating prior to the qualifying date of May 1972. The boilers were manufactured in 1957. The addition of different types of biomass as an allowable fuel is not considered a modification for PSD purposes because the boilers were capable of accommodating biomass before January 6, 1975, and using different types of biomass as an allowable fuel was not prohibited under any federally enforceable permit condition established after January 6, 1975. The emissions from the sugar drying equipment, the increase in specification used oil, the removal of bunker oil no. 6, will be counted as the allowable emissions increase and decrease for PSD purposes. For now, PSD requirements do not apply to the Puunene Mill boilers.

<u>SYNTHETIC MINOR SOURCE APPLICABILITY</u>

Synthetic Minor refers to sources which have the potential to emit greater than 100 tons per year of a regulated air pollutant, or 10 tons per hazardous air pollutant, or 25 tons per year for any combination of HAPs, but where limits are proposed to reduce emissions below these levels. A synthetic minor source is a potentially major source but is made a minor source through federally enforceable permit conditions, for example, limiting the facility's hours of operation, limiting the facility's fuel consumption, or the plant’s material production throughput. Pollution control devices are considered as part of the facility.

The facility is currently classified as a major source of air pollution, and the applicant does not propose any federally enforceable conditions to keep emissions below major source triggering levels. Therefore synthetic minor source applicability does not apply.

<u>BACT Requirements</u>

Best Available Control Technology (BACT) analysis applies to new and modified sources if the net increase in pollutant emissions exceed "significant levels" as defined in HAR §11-60.1-1, considering any limitations, enforceable by the Department of Health, on the source to emit a pollutant. BACT is an emissions limitation based on the maximum degree of reduction for each pollutant, on a case-by-case basis, the applicant eliminates or supports step-by-step pollution control options, beginning at the top of a list of best available pollution control technology, taking into account:

(1) Energy;
(2) Environmental; and
(3) Economic impacts and other costs, if achievable through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the pollutant.

See project emissions below in Tables 8-13, for individual and total plant emissions. The permittee removed burning fuel oil no.6, and increased specification used oil from 1.5 million gallons to 2 million gallons, plus the sugar dryer emissions. By calculations, with a decrease in emissions by eliminating bunker oil no.6, increasing used oil, adding wood chips, the calculated net potential emissions for the boilers does not exceed the "significant level". BACT is not required.

TABLE 7 SIGNIFICANT LEVELS EMISSON RATES MUST BE EQUAL TO OR GREATER THAN THE GIVEN TONS PER YEAR (tpy)	
POLLUTANT	**TON PER YEAR (tpy)**
Carbon Monoxide	100
Nitrogen Oxides:	40
Sulfur Dioxide	40
Particulate Matter	25
Particulate Matter less than 10 micrometers:	15
Particulate Matter less than 2.5 micrometers	10
Ozone	40 of Volatile Organic Compounds (VOCs)
Lead	0.6
Asbestos	0.007
Beryllium	1.001
Vinyl Chloride	1
Fluorides:	3
Sulfuric Acid Mist:	7
Hydrogen Sulfide:	10

<u>Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI-ICE)</u>

40 CFR Part 60, Subpart IIII, applies to any stationary internal combustion engine, such as diesel engines (DE), including reciprocating or rotary, that converts heat energy into mechanical work. This definition excludes mobile and spark ignition (SI), engines.

Applicable CI-ICE dates are:

1. July 11, 2005 is the commenced construction date.
   The date of construction is defined as the date the engine is ordered by the owner or operator; and
2. April 1, 2006 is the manufactured date.

The format of the final standard is an output-based emission standard for PM, NO_X, CO, and NMHC (non methane hydro carbons) in units of emissions mass per unit work performed (grams per kW-hr) and smoke standards as a percentage. The emission standards are generally modeled after EPA's standards for nonroad and marine DE. The nonroad DE standards are phased in over several years and have tiers with increasing levels of stringency.

Stationary ICE differs from mobile ICE in that it is not a nonroad as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle.

A SI engine means a gasoline, natural gas, or liquid petroleum gas (LPG) fueled engine, or any type of engine with a spark plug or other sparking device, and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation.

Dual-fuel engines in which a liquid diesel fuel is used for CI and gaseous fuel, typically natural gas, is used as the primary fuel at an average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are SI engines.

CI-ICE is not applicable because the diesel engines and diesel engine generators at the Puunene Sugar Mill will be only operated to supply electricity for emergency situations during electrical power outages and for maintenance purposes.

INSIGNIFICANT ACTIVITIES

Insignificant Activities at the Puunene Mill are listed below.

1. Motor-burnout oven (0.625 MMBtu/hr)
2. Wood fired refractory curing within boilers
3. Emergency diesel generator (355 HP)
4. Various welding booths (5) in mill Industrial Shops
5. Secondary fire pump (280 HP)
6. Fuel storage tanks and liquid fuel dispensers:

   a. Liquid fuels for the boilers and the Puunene Mill mobile equipment are stored in above ground storage tanks on the Puunene Mill grounds. The above ground storage tanks range from 250 to 25,000 gallons, and contain propane, diesel, specification used oil, and gasoline. Lubricants, hydraulic fluids, and other petroleum products are also stored in various tanks. (See the April 2007 application Table A-1R[1] for capacities and contents, and Tables A-1R and A-2R[1] for locations.); and

b. Fuel dispensers for Puunene Mill vehicles are:

   i. Gasoline dispensers are located adjacent to the eastern end of Tank PU-31 (see Figure A-2R in the April 207 application) and consist of two Gasboy dispensers, each with two (2) hoses and a nozzle on each hose;
   ii. One Gasboy low sulfur on-road diesel dispenser is adjacent to Tank PU-41, and has two 1-inch hoses and a nozzle on each hose; and
   iii. Two (2) Gasboy off-road diesel dispensers are located southeast of the cane hauler shop, and each has two (2) two-inch (2-inch) hoses with an OPW nozzle on each hose.

7. Fuel and material storage piles
8. Lime Handling System and Pellet Lime Slaker, and storage bin
9. Oil fired water heater pressure washer located at Tractor Shed wash rack (Landa Model EOF6-3000, 0.558 MMBtu/hr)
10. Oil fired water heater located at Cane Truck Stop wash rack (Hotsy Model 5830A, 0.98 MMBtu/hr)
11. LPG fired water heater located at HSPA Experiment Station (RECO LP Gas Model #3XA-505-80T (0.505 MMBtu/hr input)
12. 0.625 MMBtu/hr BAYCO propane (LPG)-fired heat cleaning oven, Motor Shop
13. Sugar granulator
14. Sugar cooler
15. 63 hp and 80 hp portable diesel fired air-compressors, Construction Shop
16. 22 hp portable diesel fired pressure washer, Tractor Shop
17. Various portable diesel fired welding machines, electric generators, air compressors, and other industrial equipment less than 143 hp used for maintenance and repairs
18. Temporary diesel generators operated during annual facility power outage for maintenance
19. 40 hp Jet-Crete portable gasoline-fired gunite machine, Construction Shop
20. Various portable diesel fired welding machines, electric generators, air compressors, and other industrial equipment less than 143 hp used for maintenance and repair
21. Solvent cleaning and degreasing
22. Electrical varnish dip tank
23. Mixing of powdered herbicides
24. Painting, woodworking, sand blasting operations
25. Seed treatment dip tanks
26. Bagacillio collection and transfer systems:

    a. The bagacillio system provides fine bagasse (that is, bagacillio) to the mud filters in the boiling house. This system collects fine bagasse from the bagasse house via a blower and ducts, and routes the fine bagasse through a cyclone that deposits the bagasillio onto a screw conveyor for use as a filter medium; and
    b. The cyclone exhausts to a stack in the wall of the boiling house. This stack has a rain cap.

27. Plant maintenance and upkeep activities.

Insignificant Activity not at the Puunene Sugar Mill is listed below.

28. Emergency 66 hp diesel engine generator, located at the old Paia Sugar Mill (presently closed), approximately six miles from the Puunene Sugar Mill.

ALTERNATE OERATING SCENARIOS

None proposed.

AIR EMISSIONS EVALUATION – PROJECT EMISSIONS

The majority of the emissions from the facility results from the operation of the three (3) steam boilers. The criteria pollutants are nitrogen oxides (NO_x), sulfur dioxides (SO_2), carbon monoxide (CO), volatile organic compounds (VOC) and particulate matter 10 microns or less in size (PM/PM_{10}). Non-criteria pollutants include arsenic, benzene, beryllium, fluorides, lead and mercury. All of these non criteria pollutants except benzene would result only from traces of these elements in the boiler and internal combustion engine fuels. Benzene emissions are a fraction of non-methane hydrocarbon emissions, which may result from either combustion or evaporation sources.

With the exception of annual source performance stack testing, the three (3) boilers do not normally fire one-hundred percent fuel oil or specification used oil. The oil is normally used as a supplement to burning bagasse.

The April 2007 application maximum potential to emit hazardous air pollutants for coal for Boilers I and 2 are based on 54,680 tons per year and Boiler 3 is based on 45,000 tons per year

TABLE 8 MAXIMUM EMSSION RATES for BOILERS 1 & 2 (COMBINED)		
POLLUTANT	MAXIMUM EMISSION RATE lb/hr	EMISSION FACTORS BASED ON:
NO_x	223	10/92 source test for HC&S Puunene Boilers 1&2 burning at the same time on coal and April 2007 application burning coal
SO_2	326	April 2007 application burning coal
CO	1788	April 2007 application burning bagasse
VOC	93	April 2007 application burning bagasse
PM/PM_{10}	199.3 109	10/92 source test for HC&S Puunene Boilers 1&2 on Bagasse April 2007 application.burning bagasse
Lead	0.13	April 2007 application, TSM* burning coal (0.55 tn / yr)
NON CRITERIA POLLUTANTS		
Arsenic	0.13	April 2007 application, TSM burning coal (0.55 tn / yr)
Benzene	19.2	April 2007 application, burning bagasse

TSM is an acronym for Total Selected Metals which generally means the combination of the following 8 metallic HAPs: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and selenium.

To determine the emissions from Boiler 3, the worst-case emission rates for PM, SO_2, and NO_x were determined using the Federal New Source Performance Standards and EPA's Air Pollution (AP) - 42 from the following:

TABLE 9
MAXIMUM EMISSION RATES for BOILER 3

POLLUTANT	MAXIMUM lb/hr EMISSION RATE	EMISSION FACTORS BASED ON:
NO_x	253.5 306	10/92 source test for HC&S Puunene Boilers 1&2 on coal April 2007 application, burning coal
SO_2	372	April 2007 application, burning coal
CO	858.3 858	AP-42 Section 1.6, Wood Waste Combustion (2/99) April 2007 application, burning wood chips
VOC	13.6 13.6	AP-42 emission factor for wood combustion of 0.22 #/ton fired April 2007 application, burning bagasse
PM/PM_{10}	48	April 2007 application, burning bagasse
Lead	0.08 0.44	#6 Fuel oil analysis - 1989 HC&S April 2007 application, burning coal (0.46 ton/yr)
NON CRITERIA POLLUTANTS		
Arsenic	0.44	April 2007 application, burning coal (0.46 ton / yr)
Benzene	< 0.02 7.9	Study of emission sources by the California Air Resources Board (1986) April 2007 application, burning bagasse (34.58 tn / yr)

To determine annual emissions from the boilers, emissions from each allowable combination of fuels was considered. The possible fuel combinations take into consideration permit conditions which require a minimum of 50% of the total annual heat input to the boilers to be biomass. In the cases where the maximum emission rate is derived from a fossil fuel, annual emissions are determined by multiplying the emission factors for both fuel oil and bagasse by the appropriate hours of operation.

TABLE 10 CRITERIA POLLUTANT MAXIMUM POTENTIAL EMISSIONS (ton per year)					
EMISSION SOURCE	NO_X	SO_X	CO	NMHC	PM/ PM_{10}
Boilers 1 and 2	679	730	7,830	407	479
Boiler 3	880	693	3,757	60	212
Totals	1,559	1,411	11,586	466	691

Emissions from the 20,000 lb/yr sugar dryer, consisting entirely of particulate matter, were calculated using the following:

TABLE 11 MAXIMUM EMISSION RATE from THE 20,000 lb/hr SUGAR DRYER		
POLUTANT	MAXIMUM EMISSION RATE (lb/hr)	EMISSION FACTORS BASED ON:
PM/PM_{10}	49.8 1.46	Information provided by Manufacturer April 2007 application

Emissions (lb/hr) = (0.02gr/dscf) x (8,500 scf/min) x (1 lb/7,000 grains) x (60 min/1 hr)
= 1.46 lb/hr

where 0.02 gr/dscf = vendor guaranteed emission rate
8,500 scf/min = maximum airflow from scrubber stack

Emissions (lb/ton sugar) = (1.46 lb PM/hr) x (1hr/20,000 lb sugar) x (2,000lb/ton)
= 0.146 lb PM / ton sugar

where 20,000 lb sugar/hr = maximum sugar processing rate of dryer

Inputting the annual sugar production limit of 75,000 tons,

Emissions (PM) = (0.146 lb PM / ton sugar) x (75,000 tons sugar/year)
= 10,950 lb/yr
= 5.48 tons/yr

Annual emissions from the 20,000 lb/hr sugar dryer consist entirely of particulate matter and due to the wet scrubber, are slightly less than one ton per year. The applicant's April 2007 application estimates less than 2 tons per year. The total emissions from the Puunene Mill are exhibited in Table 12.

TABLE 12 HAZARDOUS AIR POLLUTANTS (HAPS)		
FUEL	BOILERS 1 and 2 (tpy)	BOILER 3 (tpy)
Bagasse	114.8 on 3,714,240 MMBtu/yr	57.5 on 4,975,680 MMBtu/yr
Coal	3.0 on 54,680 ton/yr	2.4 on 45,000 ton/yr
Wood Chips	12.1 on 3,714,240 MMBtu/yr	16.2 on 4,975,680 MMBtu/yr
Fuel Oil No 2	0.31 on 1,668,758 MMBtu/yr	0.37 on 2,031,736 MMBtu/yr
SpecificationUsed Oil	0.16 on 210,714 MMBtu/yr	

AIR POLLUTION CONTROL DESCRIPTION

The three boilers are equipped with primary and secondary particulate emission control systems. The primary control system consists of a bank of multi-cyclones manufactured by Western Precipitation Corp. During the bagasse off-season of 2010 -2011, that is, generally from late November to early March, HC&S replaced the Boiler 2 multiclone with a new Barron Fan Technology, Inc. multiclone equipped with 9-inch collection tubes. Boilers 1 and 2 are equipped, each with one set of multi-cyclone dust collectors exhausting through the 150 ft Stack 1. Stack 1 is fitted with a venturi wet scrubber. Boiler 3 is equipped with 2 sets of multi-cyclone dust collectors and exhaust through the 140 ft Stack 2 also fitted with a venturi wet scrubber.

Multi-Cyclone Dust Collectors

Also known as (aka) multiclone, there is one multi-cyclone servicing Boiler 1, another multi-cyclone servicing Boiler 2 and two (2) multi-cyclones servicing Boiler 3.

A cyclone dust collector is an enclosed, conical tube. Particle filled air is pumped in at an upper section collecting tube through the inlet guide veins above the wide end of the cyclone. The veins guide the air coming in at an angle, it moves down the cone in a spiral, increasing in speed as the cone's circumference grows smaller. This creates a vertex much like a tornado or cyclone. Larger particles are thrown against the side walls of the cone and drops by gravity to a discharge bin at the bottom. A fan at the top of the cyclone cone draws lighter particles and the air up the center of the cyclone to an exhaust tube or outlet, usually to a filter for catching fine particles. The height of the cone, diameter of the cone, and the angle of the walls all affect the efficiency of particle removal.

Mutiple cyclone cones can be set in parallel with each other to remove more dust from the air. Often these will be smaller diameter cones with longer lengths than a single cone collector. Multiclones, as these systems are called, use a single inlet and outlet for all the cones together.

Collectors are available with 6 inch, 9 inch and 11.5 inch diameter collection tubes. Theoretically, high-collection efficiencies are achieved with the smaller 6 inch or 9 inch diameter tubes, since the centrifugal force applied to the dust particles increases as the tube diameter decreases. Three other design factors significantly affect collection efficiency, (1) proper gas distribution, (2) draft loss, and (3) particle size/specific gravity.

The multi-cyclones employ a centrifugal force generated by a spinning gas stream to separate particulate matter from the exhaust gas. An efficient multi-cyclone can remove approximately 96% of the particulate matter contained in the flue gas leaving a boiler.

The primary means of PM control for the Puunene Mill's Boiler 2 is the venturi wet scrubber. The new multiclone dust collector provides partial control of PM emissions, and also assists to reduce abrasive wear on the induced draft fan and ducting downstream to the venturi wet scrubber and air emissions from Stack 1.

Venturi Wet Scrubber

The venturi wet scrubber removes approximately 95% of the remaining particulate matter. To maximize absorption of gases, venturi are designed to operate at different conditions from collecting particulate matter (PM).

A venturi scrubber consist of 3 sections: (1) a converging section, (2) a throat section, and (3) a diverging section. The inlet gas stream enters the converging section, and as the area decreases, gas velocities increase (in accordance with the Bernoulli equation). Liquid is introduced either at the throat or at the entrance to the converging section.

Most venturis operate with pressure drops in the range of 20 to 60 inches of water. At these pressure drops, the gas velocity in the throat is usually between 100 to 400 feet per second (ft/s) or approximately 270 miles per hour (mph) at the high end. These pressure drops result in high operating costs.

The liquid injection rate or liquid to gas ratio (L/G) also affects particulate matter collection. The proper amount of liquid must be injected to provide adequate liquid coverage over the throat area and make up for any evaporation losses. If there are insufficient liquid, then there will be not enough liquid targets to provide the required capture efficiency.

Most venturi systems operate with a L/G of 3 to 10 gal /1000 cubic-feet (cu-ft). L/G ratios less than 3/gallons/1000 cu-ft are usually not sufficient to cover the throat, and adding more than 10 gal/1000 cu-ft does not usually significantly improve particle collection efficiency.

To maximize the absorption of gases, venturis are designed to operate at a different set of conditions from those used to collect particles. The gas velocities are lower and liquid-to-gas ratios are higher for absorption.

The primary maintenance problem for venturi scrubbers is wear, or abrasion, of the scrubber shell because of high velocities. Gas velocities in the throat can reach speeds of 270 mph. Particles and liquid droplets traveling at these speeds can rapidly erode the scrubber shell.

Venturis are not as efficient for absorbing pollutant gases as are packed or plate towers.

The method of liquid injection at the venturi throat can also cause problems. Spray nozzles are used for liquid distribution because they are more efficient with a more effective spray pattern for liquid injection than weirs. However, spray nozzles can easily plug when liquid is recirculated. Automatic or manual reamers can be used to correct this problem.

The venturi flow rate is dependent on the water pressure. The owner stated that the venturi wet scrubber water flow rate may not be attainable due to decrease in exhaust gas flow during boiler startup despite adjustments to the scrubber damper to compensate the lower flow.

As an alternative to continuous opacity monitoring (COMs) from the stacks, HC&S has submitted a proposal to monitor the wet scrubbers' operating parameters. Also, the applicant has plans that the wet scrubber for Boiler 3 be run in either the "Once Through" mode on in the "Recirculation" mode to conserve water. Proposed operating parameters for the scrubbers are shown in Table 14, Table 15, and Table 16 below.

The following flow rates are a submitted proposal:

**TABLE 13 BOILER 3 VENTURI WET SCRUBBERS
MINIMUM WATER FLOW RATES
(gallons / minute)
ON a SIXTY (60) MINUTE ROLLING AVERAGE**

MODE of OPERATION	MINIMUM WATER FLOW RATES (gallon/minute)
Recirculation Mode:	
Coal Firing	2,000
Bagasse Firing Alone or With Fuel Oil	2,200
Oil firing	2,050
"Once through" Mode:	
Coal Firing	1,400
Bagasse Firing Alone or With Fuel Oil	1,400
Oil firing	1,600

The permittee had also proposed to operate and maintain gauges to measure the pressure drop, in inches of water, across the wet scrubber. The gauges would have been installed as close to the wet scrubbers as is practical or as specified by the manufacturer. The permittee had proposed to maintain differential pressures, in inches of water on a sixty (60) minute rolling average, across the three (3) venturi wet scrubbers as follows:

TABLE 14 BOILER 3 VENTURI WET SCRUBBERS MINIMUM DIFFERENTIAL PRESSURES (inches of water) ON a SIXTY (60) MINUTE ROLLING AVERAGE	
MODE of OPERATION	MINIMUM DIFFERENTIAL PRESSURE (inches of water)
<u>Recirculation Mode:</u>	
Coal Firing	5.0
Bagasse Firing Alone or With Fuel Oil	4.0
Oil firing	4.2
"<u>Once through" Mode</u>:	
Coal Firing	5.5
Bagasse Firing Alone or With Fuel Oil	4.0
Oil Firing	4.5

Both Tables 13 and 14 above were combined into one as shown below in Table 15, which is presented in the owner's April 2007 application. Seeing the water flow rate and the related water pressure together in one table makes it easier to comprehend the job of the flow meter and pressure gauge working together to sustain the flow rate for maximum pollution control.

TABLE 15 BOILER 3 VENTURI WET SCRUBBER		
MODE OF OPERATION	MINIMUM FLOW RATES (gal/min)	MINIMUM DIFFERENTIAL PRESSURE (inches of water)
<u>Recirculation Mode</u>:		
Coal Firing	2,000	5.0
Bagasse Firing Alone or With Fuel Oil	2,200	4.0
Oil firing	2,050	4.2
"<u>Once through" Mode</u>:		
Coal Firing	1,400	5.5
Bagasse Firing Alone or With Fuel Oil	1,400	4.0
Oil Firing	1,600	4.5

<u>Entoleter Model 0405 Wet Scrubber</u>
The Entoleter Wet Scrubber is used in conjunction with the 20,000 lb/hr rotary sugar dryer. The dryer system is located upstream of the existing sugar packaging plant. The scrubber is used to

remove sugar dust sucked in the dryer air flow. The scrubber operates with a pressure drop of 8 inches of water and a recirculation rate of 40 gallons per minute. The scrubbed air is then routed via an induced draft fan to a 20 inch diameter, 50 foot tall exhaust stack. The maximum airflow from the scrubber stack is 8,500 standard cubic feet per minute (SCFM).

Flue-Gas Desulfurization

Flue-gas desulfurization (FGD) is a technology used to remove sulfur dioxide from exhaust flue gases of fossil fuel power plants. Fossil-fuel power plants burn coal or oil to produce steam for steam turbines, which in turn drive electricity generators.

Flue gas is gas that flows out to the atmosphere through a flue, which is a pipe or channel for the exhaust gases to escape from a fireplace, oven, furnace, boiler or steam generator. Tall flue-gas stacks dispurse (spreads) emissions by diluting the pollutants in ambient air.

Sulfur dioxide can be removed from flue gases by a variety of methods. The following are common methods:

1. Wet scrubbing using a slurry of alkaline sorbent, usually limestone or lime, or sea water to scrub gases.
2. Spray-dry scrubbing using similar sorbent slurries.

Many venturi scrubbers are designed to remove particulate matter.

Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

In accordance with 40 CFR Part 60, Subpart D, §60.45, the permittee shall install, operate, calibrate, and maintain a continuous opacity monitoring system (COMS) for measuring opacity and a continuous emissions monitoring system (CEMS) for measuring sulfur dioxide (SO_2) emissions, nitrogen oxide (NO_2) emissions, and either oxygen (O_2) or carbon dioxide (CO_2) emissions.

AMBIENT AIR QUALITY ANALYSIS

To demonstrate compliance with State and Federal Ambient Air Quality Standards, plume impacts in simple terrain under downwash conditions were estimated using the US Environmental Protection Agency's AERMOD model. This model is designed to evaluate a wide variety of sources within an industrial source complex. The model can account for settling and dry deposition of particulates; downwash (is the disrupted flow of the wind as it blows over a solid structure); area, line and volume sources; plume rise as a function of downwind distance; separation of point sources; and elevated receptors. The model is capable of estimating concentrations for a wide variety of averaging times ranging from 1 hour to 1 year.

AERMOD was used to evaluate impacts on all receptors, including those close to the stack where building downwash was expected to occur. The model was run using on-site meteorological data collected at the Puunene sugar mill between February 2002 and January 2003.
The stack parameters used to determine compliance with state and federal ambient air quality standards are displayed in Table 16.

Table 16 **STACK EMISSION PARAMETERS**				
PARAMETER	STACK No. 1 (BOILERS 1 & 2)		STACK No. 2 (BOILER 3)	
Diameter	3.96 m	13 feet	3.66 m	12 feet
Height	46.94 m	154 feet	42.67 m	140 feet
Velocity	7.51 m/sec	24.6 feet/sec	12.71 m/sec	41.7 feet/sec
Temperature	330.44 K	135 EF	323.33 K	122 °F

HC&S has proposed to eliminate the burning of fuel oil no. 6. Long-term (annual) emission rates have been adjusted to take into account the Boiler 3 requirement, which requires a minimum of 50% of the annual heat input to be biomass, presently bagasse. The gram per second emission rates used in the ambient air quality analysis are as follows:

TABLE 17 **POLLUTANT EMISSION RATES** **(g/s)**		
POLLUTANT	STACK No. 1 (BOILER 1 & 2)	STACK No. 2 (BOILER 3)
Sulfur Dioxide	41.13	46.81
Nitrogen Dioxide	28.06	38.54
Carbon Monoxide	225.2	108.07
Particulate Matter	13.78	6.09

The EPA guidance for the new EPA national 1-hour nitrogen dioxide ambient air quality standard of 100 parts per billion, which is equal to 188 micrograms per cubic meter, is based on the 98th percentile daily maximum total hourly nitrogen dioxide concentration that were averaged across each 3 year period in the analysis period. For HC&S, because they have only one year of representative met data available, the 3 year procedure could not be followed.

Because there were 329 valid days in the HC&S background NO_2 data set, the 7th highest value is the 98th percentile value.

322/329 = 0.978

The results of the AERMOD run for the highest 98th percentile value of the daily 1-hour concentrations at any receptor is 168 micrograms per cubic-meter from the Ozone Limiting Method (OLM) and 186 micrograms per cubic meter from the Plume Volume Molar Ratio Method (PVMRM).

The maximum worst-case predicted ambient air quality impacts as determined from the AERMOD model are summarized in Table 18.

TABLE 18
PREDICTED AMBIENT AIR QUALITY IMPACTS
BY ALL 3 HC&S PUUNENE MILL BOILERS

AIR POLLUTANT	AVG. TIME	MAXIMUM MODELED CONCENTRATIONS[4] ($\mu g/m^3$)	HAWAII[5] (NATIONAL) STANDARD	PERCENT STANDARD
SO_2	3-Hour	750	1,300	58
	24-Hour	155	365	42
	Annual	15	80	19
NO_X	1-Hour[2]	186	(188) [8]	99
	Annual[1]	12.4	70	18
CO	1-Hour	5,909	10,000	60
	8-Hour	1,309	5,000	26
PM_{10}[6]	24-Hour	30.7	150	20
	Annual	5.8	50	12
$PM_{2.5}$[7]	24-Hour	30.7	(35) [8]	88
	Annual	5.8	(15) [8]	39

[1] NO_x annual adjusted to NO_2 using Ambient Ratio Method (ARM) and national default conversion factor of 0.75.
[2] NO_x 1-hour concentration by Plume Volume Molar Ratio Method (PVMRM).
[3] Background not required for initial covered source permit for an existing source.
[4] Maximum concentrations from the April 2007 revised application used December 2004 analysis, except NO_X 1-hr was submitted to DOH September 2010
[5] The more stringent (lesser concentration) of the federal and state standard.
[6] Particulate matter equal to or less than ten microns in aerodynamic diameter.
[7] Particulate matter equal to or less than 2.5 microns in aerodynamic diameter.
[8] (Values) in parenthesis are new or recently revised air quality standards

SIGNIFICANT PERMIT CONDITIONS

Significant permit conditions include the following:

1. The multi-cyclone dust collector and the venturi wet scrubber will be in operation at all times servicing the corresponding boiler when the boiler is in operation.
2. For Boiler 3, Code of Federal Regulations (CFR) Part 60 Subpart D applies to emission limits for nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2).
3. For Boiler 3, Part 60, Subpart D requires Continuous Emissions Monitoring Systems(CEMS) to monitor sulfur dioxides and nitrogen oxides emissions.
4. For Boiler 3, Part 60 Subpart D also requires Continuous Opacity Monitoring Systems (COMS). All request by the permittee for alternate procedures for COMS and CEMS must be processed through the Administrator of U.S. EPA, Region 9.
5. For Boiler 3, all fuels, that is fuel oil no. 2, specification used oil, and coal shall contain no more than 0.5 percent sulfur by weight.

6. For Boilers 1 and 2, specification used oil obtained from commercial sources shall contain no more than 0.75% sulfur by weight, 0.5% sulfur content by weight in coal, and less than 2% sulfur content by weight for fuel oil.
7. HC&S shall not burn, but properly dispose the used oil if declared or determined to be a hazardous waste or if the analysis of the used oil indicates any exceedances of the allowable limits given in permit and is declared off-specification.
8. The maximum throughput of coal to Boiler 3 is 45,000 tons per rolling twelve-months (12-months.
9. The annual heat input from coal to Boilers 1 and 2 shall be 62,606 tons per rolling twelve-months (12-months). The above 2 coal maximum values were used to calculate the maximum potential to emit criteria and hazardous air pollutants.
10. The 20,000 lb/hr sugar dryer is limited to processing 75,000 tons of sugar as measured on a rolling twelve-month (12 month) basis.

CONCLUSION

Based on the information submitted by the applicant, it is the determination of the Department of Health that the existing facility will be in compliance with 40 CFR, Part 60, Subpart A and Subpart D, and the HAR Chapter 11-60.1, and will not cause or contribute to a violation of any Hawaii state or national ambient air quality standards

The facility is in compliance with state and federal regulations with regards to air pollution. Therefore, the Hawaii DOH intends to issue this covered source permit no. 0054-01-C to HC&S, subject to 30-day public comment period and 45-day EPA review and final permit conditions.

October 2011
Glenn Nagamine